

Design, Operation, and Troubleshooting of Dual Gas-lift Wells

API RECOMMENDED PRACTICE 19G9
SECOND EDITION, APRIL 2015



AMERICAN PETROLEUM INSTITUTE

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

Users of this Recommended Practice should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

All rights reserved. No part of this work may be reproduced, translated, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 1220 L Street, NW, Washington, DC 20005.

Copyright © 2015 American Petroleum Institute

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the specification.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the specification.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 1220 L Street, NW, Washington, DC 20005.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

Contents

Page

1	Scope	1
2	Terms, Definitions, Acronyms, and Abbreviations	1
2.1	Terms and Definitions	1
2.2	Acronyms and Abbreviations	4
3	Benefits of Dual Wells	4
3.1	General	4
3.2	More Efficient Drilling	4
3.3	Dual Gas-lift Alternatives	4
4	Dual Gas-lift Practices	5
4.1	General	5
4.2	Practices That Are Recommended	5
4.3	Defining Unacceptable Wells	6
4.4	Considering Alternatives to Dual Gas-lift	6
4.5	Dual Gas-lift Well Design Issues	6
4.6	Dual Gas-lift Operations	7
4.7	Poor Candidates for Dual Gas-lift	8
4.8	Considering Artificial Lift Alternatives to Dual Gas-lift	8
5	Dual Gas-lift Well Designs	9
5.1	General	9
5.2	Mandrel Spacing	9
5.3	Gas-lift Mandrel Spacing Production Pressure Design Line Options	11
5.4	Gas-lift Mandrel Spacing Design Procedure	12
5.5	Installation Issues	14
5.6	When One Zone Is Much Deeper than the Other	14
5.7	PPO and IPO Gas-lift Valves Compared	16
5.8	Unloading Gas-lift Valves	19
5.9	Operating Unloading Gas-lift Valves	19
5.10	Designing for Dual Gas-lift if Mandrels Spaced Too Far Apart	20
5.11	Dual Gas-lift System Design Options	21
6	Dual Gas-lift Well Operations	22
6.1	General	22
6.2	Installing Dual Gas-lift Equipment	22
6.3	Dual Gas-lift Well Wireline Operations	24
6.4	Additional Recommended Wireline Procedures	25
6.5	Unloading Dual Gas-lift Wells	28
6.6	Kicking Off Dual Gas-lift Wells	30
6.7	Operating Dual Gas-lift Wells	31
6.8	Dual Gas-lift Well Optimizing	32
7	Dual Gas-lift Well Surveillance	34
7.1	General	34
7.2	Wireline Operations	34
7.3	Pressure/Temperature Surveys	35
7.4	Evaluating with Pressure/Temperature Surveys	36
7.5	Fluid Levels	38
7.6	Well Tests	38
7.7	CO ₂ Tracer	39

Contents

	Page
7.8 Continuous Monitoring and Control	39
8 Dual Gas-lift Diagnosis and Troubleshooting	41
8.1 General	41
8.2 Diagnostic Techniques	42
8.3 Locating Communication Problems	47
8.4 Dual Gas-lift Typical Problems	48
9 Dual Gas-lift Well Automation	50
9.1 General	50
9.2 Automation Logic	50
9.3 Key Measurement Parameters	51
9.4 Dual Gas-lift Controls	53
9.5 Responding to Gas-lift System Problems	53
10 Dual gas-lift Special Issues	54
10.1 General	54
10.2 Gas-lift and a Flowing Well in One Wellbore	54
10.3 Gas-lift and a Pumping Well in One Wellbore	55
10.4 Intermitting One or Both Zones	55
10.5 Important Consideration for Completing With or Without Mandrels	56
10.6 Transitioning from Flowing to Dual Gas-lift Operation	57
Annex A (informative) Overview of Dual Well Gas-lift Systems	59
Annex B (informative) Dual Gas-lift Mandrel Spacing Design	79
Annex C (informative) Dual Gas-lift Unloading Valve Design for PPO Valves	84
Annex D (informative) Dual Gas-lift Practices Not Recommended	88
Bibliography	89
Figures	
1 Mandrel with Injection String Beneath the Upper Packer	1
2 Gas-lift Response Curve	33
3 Flowing Pressure Survey	44
4 Inflow Performance Relationship	44
5 Gas-lift Response Curve	45
6 Gas-lift Response Curve Comparison	46
7 Production Rate vs Mandrel Depth	46
B.1 Gas-lift Mandrel Spacing	83
C.1 Graphical Method for Design	86
Tables	
1 Gas-lift Valve Installation Problems	28
B.1 Example Well Parameters	80
B.2 Example Gas-lift Characteristics	80
B.3 Calculated Long String Mandrel Depths	82
B.4 Calculated Short String Mandrel Depths	82
C.1 PPO Valve Calculations	87

Design, Operation, and Troubleshooting of Dual Gas-lift Wells

1 Scope

This document provides recommended practices (RPs) for the selection, design, operation, surveillance, optimization, automation, and troubleshooting of dual gas-lift wells.

The purpose of this document is to present RPs, guidelines, and tools to help obtain optimum production from dual gas-lift wells. This document also contains practices that should be avoided to minimize problems and inefficiencies that can be associated with ineffective dual gas-lift operations. Compared to single completions, dual completions typically have more operating problems, are more difficult to work over, and can produce less efficiently.

It is not the purpose of this document to recommend the practice of dual gas-lift. In some cases, dual gas-lift is problematic and often ineffective. Often it is difficult or even impossible to effectively produce both completions in a dual well using gas-lift over the long term. Where there are other feasible alternatives to produce dual wells, they should be considered. However, many dually completed oil wells should be artificially lifted initially or after reservoir pressures have declined and/or water cuts have increased. In many cases, the only practical method of artificial lift for these wells is gas-lift. Therefore, every effort should be made to design and operate dual gas-lift systems as effectively as possible.

Annexes to this RP include:

- a) an overview of dual gas-lift systems,
- b) dual gas-lift mandrel spacing designs,
- c) dual gas-lift unloading valve design for production pressure operated (PPO) valves, and
- d) dual gas-lift practices not recommended.

2 Terms, Definitions, Acronyms, and Abbreviations

2.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

2.1.1

automation

A system for monitoring, control, diagnosis, and optimization of gas-lift operations that includes measuring important gas-lift parameters, controlling gas-lift injection rate, detecting and diagnosing problems, and optimizing gas-lift operations.

2.1.2

bottomhole pressure

BHP

Normally measured at the midpoint of the perforated interval.

2.1.3

commingling (commingle)

A process where fluids from different productive formations are combined and produced through a single conduit.

2.1.4

cross-flow

The flow of reservoir fluids from one productive formation into another.

2.1.5**dual gas-lift wells**

Wells that include two production tubing strings designed to produce from two separate reservoirs, using gas-lift.

2.1.6**field life cycle**

Operating conditions from the moment the field is opened to production until it is closed and abandoned.

2.1.7**flow regime**

The prevailing gas, oil, and water geometrical distribution when flowing through a pipe.

2.1.8**flow regime classes**

Common flow regimes for gas-liquid mixtures such as bubble flow, dispersed bubble flow, plug flow, slug flow, froth flow, mist flow, churn flow, and annular flow.

2.1.9**flowing bottomhole pressure****FBHP**

Measured at the midpoint of the perforations when the well is off production.

2.1.10**gas to oil ratio****GOR**

The ratio of produced gas to produced oil.

2.1.11**hydrates**

Ice-like crystalline compounds formed by water and natural gas molecules at high pressures and low temperatures.

2.1.12**inflow performance**

The ability of fluid to flow from the reservoir into the wellbore as a function of pressure differential from the reservoir to the wellbore.

2.1.13**inflow performance relationship****IPR**

A curved relationship in barrels per day per psi drawdown.

2.1.14**inflow survey**

An evaluation of the lift gas flow used to evaluate well performance.

2.1.15**injection pressure operated****IPO**

A type of gas-lift valve used when the injection (casing) pressure is the primary opening pressure.

2.1.16**intelligent wells**

Well completions where data recording and well control can be performed remotely.

2.1.17**intermittent**

A form of gas-lift where slugs of gas are injected intermittently beneath slugs of liquid.

2.1.18**kicking off**

Bringing an off a well back to production after a period of idle time. There may or may not be fluid in the annulus to be unloaded, depending on whether or not there a leak in the tubing.

2.1.19**multilateral completions**

Well completions that have more than one wellbore branch radiating from the main borehole.

2.1.20**multipointing**

The situation where gas-lift injection gas enters the production stream from more than one position in the tubing string.

2.1.21**optimization**

Adjustments to lift gas and well flows to achieve the maximum return without causing formation or system damage.

2.1.22**production heading**

A situation where the tubing pressure is fluctuating by more than a defined amount in a defined period of time.

2.1.23**production pressure operated****PPO**

A type of gas-lift valve used when the production (tubing) pressure is the primary opening pressure.

2.1.24**productivity index****PI**

A straight-line method to define inflow performance expressed in units of production per units of pressure drop from the formation to the wellbore. Measured in barrels per day per psi drawdown.

2.1.25**PTRO**

Test rack opening pressure, measured in the test rack when the tubing pressure is atmospheric pressure.

2.1.26**static bottomhole pressure****SBHP**

Measured at the midpoint of the perforations when the well is off production.

2.1.27**supervisory control and data acquisition****SCADA**

Real-time data captured by a supervisory control and data acquisition system.

2.1.28**surveillance**

Monitoring gas-lift operations to determine performance and to detect and address problems.

2.1.29**Thornhill-Craver equation**

A commonly accepted equation used to predict the rate of gas passage through a given orifice size.

2.1.30 unloading

The process of displacing initial annular and/or tubing fluids in the well when gas-lift injection gas is started.

2.1.31 vertical pressure profile

A plot of pressure vs depth in a flowing or gas-lift well.

2.2 Acronyms and Abbreviations

BHP	bottomhole pressure
FBHP	flowing bottomhole pressure
GOR	gas to oil ratio
IPO	injection pressure operated
IPR	inflow performance relationship
PI	productivity index
PPO	production pressure operated
SBHP	static bottomhole pressure
SCADA	supervisory control and data acquisition
TVD	true vertical depth

3 Benefits of Dual Wells

3.1 General

Dual wells exist for a number of reasons; the primary ones are summarized in this section.

3.2 More Efficient Drilling

It often appears more attractive to drill one wellbore to serve two (or more) vertically oriented production zones, rather than to drill two or more separate wells to reach these same zones. In some fields, there are multiple reservoirs “stacked” on top of each other. In some fields, there may be as many as 5, 10, or even more separate reservoirs located vertically above one another. The development plans for such fields are often complex and require study.

The objective is normally to produce the reserves as quickly as feasible, while protecting the environment and being good world citizens. Multiple completions that result in significant loss or deferment of reserves and prolonged production are not recommended. It is tempting to drill one well to intersect several reservoirs, and to produce more than one of the reservoirs at the same time with the same well, to accelerate overall production. But this should be done correctly, or the benefits may not be achieved. One might ask, “Can multiple zones not be produced in the same completion without the need for trying to operate dual completions?” In selecting the best possible development approach for multiple zone reservoirs, there are a number of choices that need to be carefully analyzed.

3.3 Dual Gas-lift Alternatives

3.3.1 General

In some cases, there may be reasonable alternatives to dual gas-lift. These should be considered, recognizing the expertise necessary to effectively operate dual gas-lift wells.

3.3.2 Alternating Production from the Two Zones

In the past, wells had production rates dictated by the regulatory authorities. In those times, it was sometimes possible to produce a well's monthly allowable limit in a few days. It was also sometimes possible to produce one side, with the other side closed in, and then switch sides. This situation is rarely available today. However, it is still sometimes true that the overall production from a dual well can be increased by producing one side and then the other side. This is not the objective of this document, and if the criteria provided are followed it is possible to increase production by producing both zones simultaneously.

3.3.3 Gas-lifting One Side, Gas Assisting the Other

In some cases, one zone should be gas-lifted full time while the other zone will flow once it has been started. In this case, it may be possible to use gas to kick off the "flowing" zone if it loads up; but once it is producing, it can continue to flow on its own. It may be necessary to temporarily close in the side that is normally on gas-lift to do this, as it may also be necessary to set the pressures on the gas-lift valves differently for the two sides of the well.

3.3.4 Gas-lifting One Side, Naturally Flowing the Other

Where it is possible to flow one side while gas-lifting the other side of a dual, this is technically not dual gas-lift. If this is done correctly, the flowing well should not interfere with the single-string gas-lift operation on the other side. The issue here is likely to be possible restrictions in tubular size, due to the need to have two tubing strings in one casing.

3.3.5 Gas-lifting One Side, Pumping the Other Side

Any attempt to pump one side of a dual while gas-lifting the other side would be very rare. One of the main reasons is, it would almost be essential to pump the pumping side below a packer. This would force any gas produced from that zone to flow through the pump; however, most pumps do not perform well in the presence of gas. This alternative should only be considered in the rarest of situations.

4 Dual Gas-lift Practices

4.1 General

The purpose of this section is to summarize the dual gas-lift practices that are recommended, and those that are not recommended (also see Annex D), or to suggest the practices to be followed and those to be avoided. This section contains a summary of the practices that are specified in detail in the following sections of this document.

4.2 Practices That Are Recommended

4.2.1 General

The following dual gas-lift practices are grouped into categories for easy reference. Each recommended practice is supported by additional information in this document.

4.2.2 Selecting Acceptable Wells

The following should be performed when selecting wells for dual gas-lift:

- carefully evaluate all of the factors and only select wells for dual completion where the factors favor dual operation,
- evaluate all potential operational issues and only select wells for dual completion where there is a likelihood of long pre-gas-lift operation and/or where there is a strong likelihood of successful dual gas-lift operation.

4.3 Defining Unacceptable Wells

Avoid attempting dual gas-lift if the casing is too small or the zones are too far apart. See A.3 for additional information on candidate well selection criteria.

4.4 Considering Alternatives to Dual Gas-lift

The following are issues to consider regarding alternatives to dual gas-lift:

- consider commingling the two zones if this is feasible and allowed,
- consider developing the two zones as single completions if production will be important and it would be practically feasible to do so,
- consider alternatives if dual gas-lift expertise is not available.

4.5 Dual Gas-lift Well Design Issues

4.5.1 Mandrel Spacing

It is recommended to install mandrels to within a few tubing joints above the dual production packer. Use a conservative mandrel spacing design; place mandrels close enough together to unload and work down, regardless of the type of gas-lift valves being used. Additionally, it is recommended to space mandrels close enough together to lift at the optimum depth on both zones regardless of the well's reservoir pressure and productivity. Use the same number of mandrels for both zones. Space the mandrels in the upper zone one tubing joint above the mandrels in the lower zone.

4.5.2 When One Zone Is Much Deeper

If the tubing is large enough, use an insert string in the long side of the dual to inject gas into the long side beneath the dual zone production packer. If the tubing is not large enough for an insert string, only design mandrels down to the depth of the upper production packer. Complicated designs should be avoided because of increased mechanical risk.

4.5.3 PPO vs Injection Pressure Operated (IPO) Debate

If the expected depth of lift is known, use IPO gas-lift valves for unloading. If the expected depth of lift is not known and it may be necessary to lift from unloading valves, use PPO gas-lift valves for unloading. The use of "special" gas-lift valves (e.g. balanced IPO valves) should only be considered in special cases where use of IPO or PPO valves is not practical.

4.5.4 Unloading Valves

See Annex C for a recommended unloading design for PPO gas-lift valves.

4.5.5 Operating Valve or Orifice Valves

If the depth of lift is not known and cannot be predicted, design so that the well can operate through an unloading valve if necessary. When the depth of lift is known or can be predicted, and if flexibility is desired in the injection rate, design to operate through an orifice. If the depth of lift is known or can be predicted, if the desired injection rate is also known, and if stability is most important, design to operate through a nozzle venturi orifice.

4.5.6 Where Mandrels Are Too Far Apart

If the upper mandrels are spaced too far apart to support use of PPO, balanced IPO, or differential gas-lift valves, consider using IPO valves in the upper mandrels, until a depth is reached where the well may

operate. Then use PPO valves, or use a standard orifice or a nozzle venturi orifice if the deepest mandrel has been reached. See 4.7.2, 5.6, 5.7, 5.10, and 6.5 for more information on designing for dual gas-lift when the mandrels are spaced too far apart.

4.5.7 Various Options

Recognize that there are several alternatives or options available for selecting the types of gas-lift valves to use in dual gas-lift. No one approach is recommended in this RP. It is recommended to discuss these options with experienced operators and try the approaches that have worked the best for them. See A.6 for more information on other options available for selecting gas-lift valves.

4.6 Dual Gas-lift Operations

4.6.1 Installing Equipment

Whenever possible, install the two strings of a dual gas-lift well together. If it is necessary to run the strings separately, the long string should be run first. Have an expert from the packer supply company on site for the installation and testing of the packers on the long string and setting the short string into the dual packer. If using surface-controlled gas-lift valves, have an expert from the surface control company on site for the installation. If installing chemical injection lines, follow the same procedures as outlined for installing electrical cables or hydraulic lines. Pressure test each packer to the recommended pressure.

4.6.2 Wireline Operations/Procedures

Cross-flow between the two sides of a dual gas-lift well can occur from the higher pressure zone to the lower pressure zone when dummies or valves are pulled from the higher pressure tubing string. Set tubing plugs as needed to prevent cross-flow. See 5.10, 6.3, 6.4, 7.2, 7.3, 7.4, 8.3, and A.15 for more information on wireline operations.

Conduct casing, tubing, and packer pressure integrity tests before performing wireline operations on dual gas-lift wells. If problems occur, use the troubleshooting chart in (Table 1) to help diagnose and address the problem(s).

4.6.3 Unloading

Normally, unless there is some strong reason not to do so, unload the casing annulus using the long string, since it normally has the deeper gas-lift mandrels. Follow the detailed unloading procedures outlined in 5.2.

4.6.4 Kicking Off

If both sides of a dual need to be kicked off (restarted after a period of idle time), start with the best zone, get it stable, and then kick off the other zone. If there is a concern about the first zone “robbing” gas while ramping up to kick off the second zone, minimize this by installing chokes in the unloading valves, if IPO gas-lift valves are used. When one side of the dual is kicked off (restarted), follow the same procedure as used to kick off the second zone when both sides are restarted. See 6.6.2 and D.1 for more information on kicking off.

4.6.5 Operating

Try to keep both zones continually on production to avoid the need to restart one or both zones. Try to continuously inject gas at the desired depth in both zones. Try to inject gas in a stable manner, especially during well tests and pressure surveys. If possible, use an automatic control system that can deliver gas at the desired rate and pressure, even in the face of gas-lift system upsets. See Section 6 for more information on operating dual gas-lift wells.

4.6.6 Optimizing

Determine the optimum injection rate for each side of the dual gas-lift well. Do this using the procedures discussed in 6.8 or by using a multirate well test. Determine the allowable range of the injection rate around the

optimum rate, from minimum to maximum. Develop a control strategy to allocate gas to each dual well with the objective of keeping the injection rate within the acceptable range for the two sides.

4.7 Poor Candidates for Dual Gas-lift

4.7.1 General

The following characteristics or well conditions may make it difficult to effectively operate dual gas-lift. Many of these are “negative” corollaries of the conditions that define an acceptable candidate for dual gas-lift.

4.7.2 Two Zones Too Far Apart

If the vertical distance between the two zones is more than 305 m (1000 ft), dual gas-lift may be difficult. Gas-lift gas for the deeper zone would need to be injected above the shallow zone's production packer. This could make gas-lift of the lower zone ineffective. If the zones are far apart, it is likely that their reservoir pressures will be very different. They may make their gas-lift operating requirements different.

4.7.3 Low Formation Gas to Oil Ratio

If one or both of the zones has a low formation gas to oil ratio (GOR), it may be difficult to gas-lift the zone because all of the gas needed for production must be injected. This is particularly true if the GOR of the deeper zone is low. The production from the lower zone must flow, under the zone's inflow pressure, from the perforations of the lower zone to the depth of gas-lift injection, which will be above the depth of the shallow zone's production packer.

4.7.4 Intermittent Operation of One or Both Sides

When the reservoir pressure of a zone becomes low, or the inflow performance of the zone deteriorates, it may not be possible to maintain effective continuous gas-lift. When this happens, it may be more effective to lift the well by intermittent gas-lift. With intermittent gas-lift, gas is injected into the tubing in cycles or slugs. This intermittent action is accompanied by significant variations in injection pressure. It may not be feasible to intermit one side of a dual gas-lift well while attempting to continuously gas-lift the other side.

4.7.5 Small Casing Size

The minimum casing size where dual gas-lift should be considered is 17.78 cm (7 in.). This casing size is needed to permit use of the gas-lift mandrels that can accommodate 2.54 cm (1 in.) gas-lift valves, and this is the minimum sized gas-lift valve that can be considered for effective dual gas-lift.

4.8 Considering Artificial Lift Alternatives to Dual Gas-lift

4.8.1 Completing as Single Wells

If the wells can be completed as single producers with one wellbore for each reservoir to be produced, problems associated with dual gas-lift are avoided. This requires a detailed analysis that compares all of the issues associated with drilling, development, operational effectiveness, workover, etc.

4.8.2 Workovers and Abandonments

With dual wells, due to the extra string of tubing, packer, set of gas-lift equipment, etc., it is more challenging to complete the well than a single well. Due to the added complexity of the completion, workovers are more risky and difficult to perform. Additionally, it is more difficult to abandon a dual well because of the extra equipment in the well and the two zones that must be sealed.

4.8.3 Lack of Operating Expertise

Successful operation of dual gas-lift requires knowledge, experience, and expertise. This is not a job to be undertaken by untrained or inexperienced staff. If people with the right knowledge and experience do not

exist in the company, and if they cannot be found in appropriate and available service or consulting companies, it would be wise not to undertake dual gas-lift operations.

4.8.4 Commingling Production

If it is allowed and technically feasible to commingle the production from multiple reservoirs in the same wellbore, and if there is an acceptable way to measure or estimate the production from each zone, this may be preferable to attempting dual gas-lift operations.

4.8.5 Potential for Remedial Work

If there is a likely need to perform remedial work (e.g. through tubing perforating, squeeze cementing, sand control, etc.) for the upper zone, below the end of tubing for the upper zone, this can be very difficult, since the tubing for the deeper zone extends through this area. In this case, use of dual gas-lift may be very difficult, and it may risk the integrity of the long side and even of the entire well.

4.8.6 Using Casing Pressure for Surveillance

The casing (injection) pressure is one of the most used variables for gas-lift surveillance. For single gas-lift, this value is often indicative of which gas-lift valve (or valves) is open, where gas is being injected into the tubing, if the well is stable or unstable, what type of instability it has, what the possible cause(s) of the instability are, etc. With a dual well, since the same casing pressure affects both sides of the dual, this surveillance and diagnostic activity is more difficult.

5 Dual Gas-lift Well Designs

5.1 General

The purpose of this section is to put many misconceptions to rest and offer RPs that, if followed, can help lead to successful dual gas-lift system designs.

5.2 Mandrel Spacing

5.2.1 General

Having the correct mandrel spacing is perhaps the most important aspect of dual gas-lift design. It is essential for the well to be able to unload to the desired operating depth. It is also important since there may be occasions when one or both zones are operated from an upper gas-lift mandrel depth. The most important requirement for the mandrel spacing is to allow the well to be unloaded and to work down to the desired operating depth. For a dual gas-lift well, there is only one annulus that needs to be unloaded. The primary RP in mandrel design is to use enough mandrels to allow both zones in the dual well to be unloaded and operated at their respective depths. The options for consideration include the following.

5.2.2 Spacing Based on Requirements of the Lower Zone

Since the annulus of the dual gas-lift well is unloaded (the completion fluid is removed), one common option is to base the mandrel spacing (unloading) design on the requirements of the deepest zone, since this should result in unloading the completion fluid to the bottom operating mandrel depth of the long string. With this approach, the mandrels are spaced based on the requirements of the deeper (long) string. The mandrels for the shorter string are typically placed one tubing joint above the mandrels in the long string to avoid them at the same depths.

5.2.3 Basing the Design Spacing on the Most Prolific Zone

Basing the mandrel spacing on the requirements of the most prolific zone uses the logic that it will result in placing mandrels closer together and high in the well. These locations become important when attempting to lift from the optimum depth for a prolific (high productivity) well. Since the productivity of either zone may not be as good as anticipated, it is wise to install mandrels down to the depth of the upper zone's production

packer. This is referred to as “bracketing.” Mandrels are installed below the depth of the bottom design mandrel. Typically, these lower mandrels are spaced 91.4 m to 152.4 m (300 ft to 500 ft) apart. Again in this case, the mandrels for the short string are placed one tubing joint above the mandrels in the long string.

5.2.4 Design Spacing Based on Conditions/Needs

An alternative is to design the mandrel spacing for each side based on its own requirements. The problem with this method is that the specific requirements of each zone may not be known at the time the mandrel spacing is performed. Normally, the attempt at a specific mandrel spacing design for each zone is not recommended. Special care should be used to make sure that no two mandrels are at the same depth.

5.2.5 Design with Flexibility to Use Different Types of Valves

5.2.5.1 General

The optimum type of gas-lift valve to be used in the well may not (probably will not) be known when the mandrel spacing is designed. Therefore, the most conservative design that will accommodate the type of gas-lift valve that requires the closest spacing should be used.

5.2.5.2 Effect of Different Types of Gas-lift Valves

5.2.5.2.1 General

The different types of gas-lift valves that may be used for dual gas-lift are listed in this section. Each has different requirements and may require a different mandrel spacing to accommodate its needs.

5.2.5.2.2 PPO Gas-lift Valves

The opening and closing of PPO gas-lift valves is primarily controlled by the tubing (production) pressure. In theory, these valves can be designed to all operate with the same surface casing (injection) pressure. Therefore, if the same tubing pressure design line is used as would be used for an IPO gas-lift valve design, the mandrel spacing can be a little further apart than with IPO valves. However, in practice, a higher (further to the right) tubing pressure design line is used, so mandrels designed for PPO usage are normally closer together than mandrels designed for IPO usage. Since PPO valves may be used on one or both sides of a dual, the mandrel spacing should be close enough to accommodate this requirement.

5.2.5.2.3 IPO Gas-lift Valves

The opening and closing of IPO gas-lift valves is primarily controlled by the casing (annulus or injection) pressure. For upper unloading valves to close, the casing pressure must be reduced for each lower valve. This requires that the mandrels be spaced closer together than would be required if this annular pressure drop were not required. However, the tubing pressure design line is normally lower (further to the left) than the tubing pressure for PPO valves. Therefore, the mandrel spacing is normally wider than that required for PPO gas-lift designs. Since IPO valves may be used on one or both sides of a dual, the mandrel spacing should be close enough to accommodate their potential use, even if a different type of valve is used.

5.2.5.2.4 Balanced IPO Gas-lift Valves

Balanced IPO valves have the primary opening force from the casing (injection) pressure, but with a very high tubing effect, normally in the range of 25 %. These valves are more sensitive to changes in tubing (production) pressure than “normal” IPO valves; therefore, they are sometimes considered as an alternative to PPO valves in cases where the mandrel spacing is too wide for “normal” PPO design.

Differential pressure gas-lift valves are typically designed with two ports. They open on a lower differential between injection and production pressure and close on a higher differential pressure. Typically, they are designed by using a production pressure design line parallel to the injection pressure design line. The typical maximum differential pressure is about 2447 kPa (355 psi). The normal differential pressure is about 1724 kPa (250 psi). They require a maximum of 152.4 m (500 ft) mandrel spacing. This type of valve is normally

used in unique circumstances. One such special circumstance would be the requirement to test the casing with the valves already in place. The higher casing pressure used for testing forces these valves closed and can support a pressure test of the casing.

5.2.5.2.5 Surface Operated Gas-lift Valves

Surface operated gas-lift valves are controlled from the surface by transmitting an electrical or hydraulic signal to the valve to open or close. With these valves, no extra casing (injection) pressure drop is required. However, even if a well is going to use this type of valve, there is a possibility that another type of valve may be needed to keep the well on production if the surface controlled valve fails. Therefore, the conservative approach for mandrel spacing design should be followed.

5.2.5.2.6 Valve or Orifice at Operating Depth

It is common to use an orifice or a specially designed valve in the bottom operating gas-lift mandrel. But this should have no impact on the mandrel spacing design. However, if the likely depth of operation is not known, it is preferred to plan for operation on an unloading valve rather than placing an orifice midway in the well. Later analysis may indicate the need for an orifice to replace an unloading valve at any depth in the well.

5.3 Gas-lift Mandrel Spacing Production Pressure Design Line Options

5.3.1 General

Gas-lift mandrel spacing is performed using a design casing (annulus or injection) pressure gradient, a design tubing (production) pressure gradient, and a number of other assumptions. Options for the production pressure design line are as follows.

- a) *Tubing Pressure Gradient Curve*—This curve is calculated for a given production rate. This method is not recommended for designing mandrel spacing since the production rate is not known at this time, and the well will produce at different rates as it unloads. This method is not recommended for spacing gas-lift mandrels or designing valve settings.
- b) *Equilibrium Curve*—The well must produce along an equilibrium curve, but the equilibrium curve cannot be defined when the mandrel spacing design is performed since the well's inflow performance and production rate(s) are not known yet. This method is not recommended for designing mandrel spacing, but it is recommended for designing valve settings.
- c) *Straight-line Approximation*—This method approximates a range of equilibrium curves. It is the best method for use during design of mandrel spacing. It is not recommended for design of valve settings, since better information is then available and the equilibrium curve should be used.

5.3.2 Gradient Curves

A frequent method is to use a vertical multiphase pressure gradient curve for the production pressure design line. This method is not recommended. The reason is that the well will not be producing on this curve during the unloading process. It will be producing at various rates as it is unloaded. Initially, when unloading near the top of the well, "production" may only consist of completion fluid being displaced from the annulus. As the unloading process continues, the well will begin to produce some fluid from the formation and some from the annulus. Finally, when the well is fully unloaded, it will produce "formation" fluid from the reservoir.

5.3.3 Equilibrium Curve

The equilibrium curve describes the actual production rate when the well is gas-lifting from any particular depth. The accurate development of an equilibrium curve requires knowledge of the well's inflow performance. This information may not be (is usually not) available at the time the mandrel spacing design is being performed. An alternative to using a single equilibrium curve could be to use a suite of curves, with each representing a different inflow performance. While elegant, this is a lot of work. The method described in Annex B is much easier and accomplishes essentially the same desired result.

5.3.4 Variable Rate or 20 % Design Line Method

This method uses a straight line for the production pressure design line. It is constructed as follows.

- 1) *Top Point*—The top of the design line is set at a point equal to Equation (1).

$$P_t + 0.2 \times (P_c - P_t) \quad (1)$$

where

P_t is the design tubing-head pressure; and

P_c is the design casing-head pressure.

- 2) *Bottom Point*—The bottom of the design line is set at a point equal to P_c (at depth)—1379 kPa (200 psi).

The advantages of this method are as follows.

- *Simplicity*—Both the casing (injection) pressure design line and the tubing (production) design lines are straight lines.
- *Flexibility*—The formula for placing the top and bottom points can be adjusted to the right or left as desired. For instance, if it is desired to place the mandrels closer together high in the wellbore, move the top of the production pressure design line to the right. For instance, a position equal to Equation (2) could be used.

$$P_t + 0.4 \times (P_c - P_t) \quad (2)$$

If it is desired to space the mandrels closer together deep in the well, move the bottom of the line to the right. For instance, a position equal to P_c (at depth)—689 kPa (100 psi) could be used. The guidelines presented above have been found to work well in many instances.

5.3.5 Specific (Set) Differential Pressure from Casing Pressure

Another method for choosing the production pressure design line could be to use a constant differential or offset from the injection (casing) pressure design line. This may be appropriate if use of a differential valve is contemplated. However, this method will result in essentially constant mandrel spacing, which is generally not what is required. Normally, the mandrels should be spaced closer together deeper in the hole, since the casing pressure and the production pressure lines converge with each other deeper in the well.

5.3.6 Bracketing to Add Additional Mandrels Deep in the Well

It is recommended to space mandrels to just above the dual production packer. When the design mandrel spacing becomes less than a given distance, the normal RP is to space the bottom mandrels evenly at a fixed vertical distance apart of 91.4 m to 152.4 m (300 ft to 500 ft). This will assure that, if the well's reservoir pressure or productivity decreases with time, it will be possible to inject gas from as deep in the well as possible.

5.4 Gas-lift Mandrel Spacing Design Procedure

5.4.1 General

A number of factors should be considered in performing a gas-lift mandrel spacing design. These are listed below. A recommended design procedure is shown in detail in Annex B.

5.4.2 Pressures

The following pressures should be defined for the unloading design process.

- *Kickoff Casing (Injection) Pressure*—This is the maximum gas pressure that can be supplied to the wellhead. This value is used for the initial unloading. During initial unloading, gas pressure is used to displace completion fluid from the annulus, and the gas injection rate into the annulus is negligible.
- *Kickoff Pressure Safety Factor*—Normally, this is between 0 kPa and 345 kPa (0 psi and 50 psi) to reduce the kickoff pressure for safe unloading design. This is to assure that there will be ample pressure to start the unloading process.
- *Operating Casing (Injection) Pressure*—This is the injection pressure that can be supplied to the wellhead at the design unloading rate. This injection pressure is used when gas injection begins into the top gas-lift valve.
- *Casing Pressure Reduction for Each Deeper Gas-lift Mandrel*—This is the amount by which the casing pressure is reduced for each deeper gas-lift mandrel. This pressure drop is required to assure that the upper valves will close when operating on the lower valves. A value of between 0 kPa and 345 kPa (0 psi and 50 psi) is normally used. A common value is 207 kPa (30 psi). This value is appropriate when 3.81 cm (1.5 in.) gas-lift IPO gas-lift valves are used.

NOTE This casing pressure drop is required when spacing for IPO gas-lift valves. It is usually not required when spacing for PPO gas-lift valves.

- *Operating Tubing (Production) Pressure*—This is the production pressure that is needed to flow liquid produced from the well to the production facility.
- *Production Pressure Safety Factor*—This is the amount, normally between 0 kPa and 345 kPa (0 psi and 50 psi), to increase the production pressure for safe unloading design. This is used to assure that there will be ample pressure to produce the fluid from the well during the unloading process.

5.4.3 Fluid Gradients

The following fluid gradients and associated parameters should be defined for the unloading design process.

- *Completion Fluid Gradient*—This is the pressure gradient (in kilopascals per meter or pounds per square inch per foot) of the completion fluid in the annulus.
- *Gas Gradient*—This is the pressure gradient (in kilopascals per meter or pounds per square inch per foot) of the gas-lift injection gas. It is a function of the injection gas gravity, the injection pressure, the wellhead temperature, and the temperature at depth in the well.

5.4.4 Other Factors

The following other factors are required for the unloading design process.

- *Mandrel Depth Safety Factor*—This is the amount by which each calculated mandrel depth is reduced to assure that the unloading process can continue. Each mandrel must be located between two tubing joints. A typical safety factor is between 0 m to 15.2 m (0 ft to 50 ft).
- *Minimum Mandrel Spacing*—This is the minimum mandrel spacing distance. It is expressed in vertical as opposed to measured depth units. A typical value is between 91.4 m to 152.4 m (300 ft to 500 ft).
- *Depth of Upper Zone Production Packer*—This is the depth of the upper zone's production packer. It should be known in both true vertical and measured depth terms.

5.5 Installation Issues

5.5.1 Installing the Two Tubing Strings Separately

There may be cases where it is necessary to install each of the two dual tubing strings separately. In this case, the long string should be installed first. If the two strings are installed separately, the second (short) string and its mandrels must be installed past the first (long) string and its mandrels. The long string production packer and the short string or dual packer must both be run on the long string. When the short string is run, it will be stabbed into the short string or dual packer.

5.5.2 Installing and Pulling Both Zones at the Same Time

This is the normal RP for a dual completion. This method is preferred so that the spacing between the gas-lift mandrels on the two strings can be assured. The completion should be designed so that it will be possible to pull the tubing/mandrels from one zone past the other zone's tubing/mandrels.

5.6 When One Zone Is Much Deeper than the Other

5.6.1 General

Dual gas-lift should not be attempted if the upper and lower zones are too far apart. Normally, the maximum vertical distance should not be more than about 305 m (1000 ft). However, in some cases a well may have zones that are further apart. If this case is considered, some alternatives are discussed.

5.6.2 Alternatives Where Two Zones Are Vertically Far Apart

5.6.2.1 General

Use an injection string beneath the upper packer with side-string mandrels. With this design option, a separate injection tube is installed below the upper packer. This packer should accommodate three tubing strings and is connected to the gas-lift mandrels in the long string. These mandrels are installed in the long string beneath the upper packer, which permits gas to be injected deeper in the deep zone's tubing but isolates the injection gas from the short zone's production interval (see Figure 1). Additional options include the following.

- If the tubing is large enough, the first and simplest option is to design both gas-lift strings down to the depth of the upper zone's dual production packer. The disadvantage of this approach is that it will not be possible to inject gas deep into the lower zone of the dual well.
- An insert string may be used in the long side of the dual to inject gas into the long side beneath the dual zone production packer.
- If the casing is large enough to accommodate a three-hole packer and an injection line beneath the dual packer, use the approach illustrated in Figure 1.
- If the long string tubing is not large enough for an insert string, and the casing is not large enough to accommodate a three-hole packer and an injection line beneath the dual packer, design mandrels only down to the depth of the upper dual zone packer.

5.6.2.2 Design Both Sides Down to the Dual Packer

The simplest option is to design both gas-lift strings down to the depth of the upper zone's production packer. This packer is also known as the dual packer. The disadvantage of this approach is that it will not be possible to inject gas deep into the lower zone of the dual well.

5.6.2.3 Injection String

A second option is to use an injection string beneath the upper packer with side-string mandrels. With this design option, a separate injection tube is installed below the upper packer. This packer should accommodate three tubing strings and is connected to the gas-lift mandrels in the long string. These mandrels are installed in the long string beneath the upper packer. This permits gas to be injected deeper in the deep zone's tubing but isolates the injection gas from the short zone's production interval (see Figure 1).

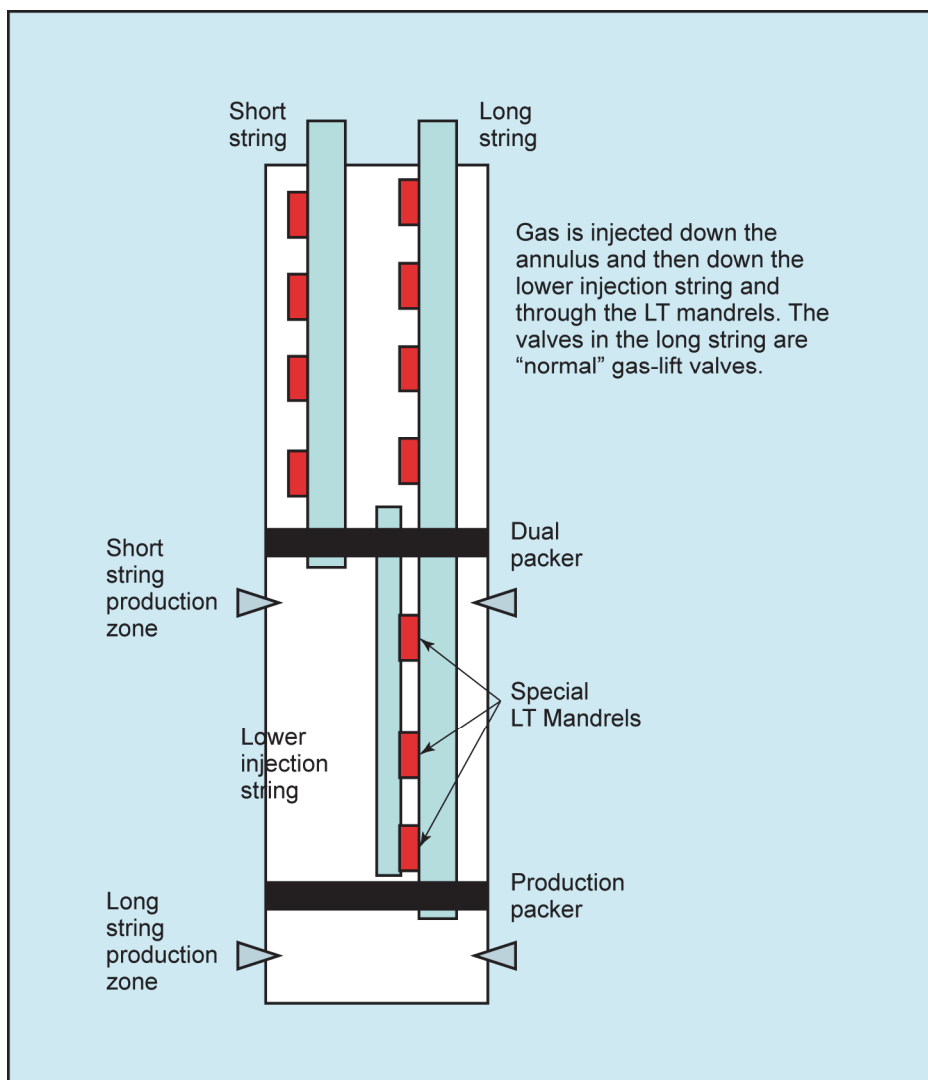


Figure 1—Mandrel with Injection String Beneath the Upper Packer

5.6.2.4 Concentric Snorkel (Dip Tube)

A third option is to use a concentric snorkel (dip tube) to inject deeper in the long string. Inject around end of dip tube, or use mandrels on the dip tube. This design includes the injection tube for the long string, below the upper dual packer, which is concentric inside the long string tubing rather than being installed on the outside of the long string tubing and connected to the long string's mandrels. Gas can be injected down the well's annulus, then into the dip tube, down the dip tube, and then into the deep zone's tubing string, either by injecting around the end of the dip tube (not recommended) or through gas-lift valves installed in the dip tube. This works where the long string's tubing size can accommodate a concentric injection string.

5.6.2.5 Comingling Two Zones

Commingle two zones and inject down the short string beneath the dual packer. If the pore pressure gradients of the short string zone and the long string zone are the same, then the zones can be commingled without risk of significant cross-flow when the wells are closed in. Additionally, if the flowing bottomhole pressure (FBHP) at the upper zone is expected to be less than the lift gas pressure at depth, the long string can be used as the production string and the short string used to deliver gas to the upper zone perforations.

To accomplish this, perform the following steps:

- a) open a sliding sleeve adjacent to the upper perforations or perforate the long string tubing at the upper zone perforation depth;
- b) install unloading valves in the mandrels of the long string, including the lowermost mandrel;
- c) install dummy valves in all of the mandrels of the short string with the exception of the lowest mandrel;
- d) install a gas-lift orifice in the lowest mandrel (short string), sized to deliver the rate of lift gas required.

To operate the well:

- a) leave the short string wellhead valves closed,
- b) open the long string wellhead valves,
- c) inject lift gas into the casing.

The unloading valves in the long string will unload/kick off the well down to the depth of the lowest mandrel. The gas-lift orifice in the short string lowest mandrel will then pass gas from the casing into the tubing and out the end of the tubing and down to the depth of the perforations or open sliding sleeve adjacent to the perforations of the upper zone. The lift gas rate is controlled normally.

5.7 PPO and IPO Gas-lift Valves Compared

5.7.1 General

It is thought by some people that the only type of gas-lift valve for a dual gas-lift well is a PPO type. The applied logic is that since there are two different zones, it is practical to let the production pressure of each zone control which valves are open, rather than the common injection pressure that may not be fully effective for either zone. Additionally, some people feel that IPO valves should be selected since the purpose is to unload the well and IPO valves are better controlled for this.

Accurate gas-lift valve performance models are available for IPO and PPO gas-lift valves. API 19G2 provides methods for accurately testing and developing performance models for gas-lift valves. Many of the commonly used IPO and PPO valves have been modeled using API 19G2. These models can be used in designing the opening and closing pressures and in determining the gas flow rates through the valves at a range of operating pressures.

5.7.2 PPO Type Valves

5.7.2.1 General

There are arguments, logic, and issues associated with using PPO gas-lift valves in dual wells. Use of PPO valves does not isolate the well from upsets in injection pressure; however, they are less sensitive to changes in injection pressure than IPO valves.

5.7.2.2 Using PPO Type Valves

The primary open/closing force for PPO valves is provided by the production (tubing) pressure. Therefore, they are less sensitive than IPO valves to changes or upsets in injection pressure. This may be a plus for PPO valves if there is a likelihood of significant changes in the gas-lift system pressure. However, there are proven techniques to maintain a relatively constant system pressure and thus avoid upsets.

5.7.2.3 PPO Valves Crossover Port Flow Restrictions

Some PPO valves have had restrictions to gas flow through their crossover ports; others have been redesigned to improve this situation. If there is any question about the performance of a specific PPO valve, it should be tested and modeled as defined in API 19G2 to accurately determine its performance.

5.7.2.4 PPO Valve “Self-adjustment”

PPO valves do not self-adjust. Once they are set, they open and close at specific values of injection and production pressure. Therefore, if the production pressure changes due to a change in the well's productivity, an upper unloading valve may reopen at the higher production pressure and allow the well to operate up the hole.

5.7.2.5 Spring-loaded PPO Valve Temperature Insensitivity

If a spring is used, in lieu of nitrogen gas charge, to provide the closing force, the valve will not be sensitive to the temperature in the well. This is not an advantage for PPO valves relative to IPO valves, since both types of valves can use a spring in lieu of nitrogen gas.

5.7.2.6 Using IPO Type Valves on Both Sides of Dual Gas-lift Wells

The primary purpose of unloading valves is to remove the liquid from the annulus so the gas-lift gas can be injected to the desired depth. If unloading were the only purpose of these valves, IPO valves would be the choice as they are well known and very commonly used for unloading single-string gas-lift wells. If both sides of a dual can be unloaded to bottom, and operated from bottom, IPO valves are the best choice.

Other types of valves are sometimes (perhaps even often) recommended for use in dual wells if it may become necessary for one or both sides of the dual to not lift from the deepest operating point, but higher. When a gas-lift well must operate “up the hole,” it may be more logical to use a different type valve that can open based on the demands of the tubing pressure, regardless of the value of the casing pressure. When one or both sides of the dual may need to lift from “up the hole,” either the design of the gas-lift valves should be changed or a different type of gas-lift valve should be considered. If it can be determined, for example, that one side of a dual must lift from the third mandrel, IPO valves can still be used if an injection orifice is installed in the third mandrel.

If both sides of a dual well can be successfully unloaded down to the desired operating depth, and if they can be operated at that depth, IPO valves should be the first choice. This includes the case where the necessary operating depth changes in one zone, if the gas-lift string can be redesigned to place an operating valve or orifice at the required operating depth. If it is unlikely that both sides of a dual can be operated at the desired depth, and if the actual depth of operation in one or both zones is not known, then IPO valves may not be the best choice.

5.7.2.7 Injection Pressure Drop to Close Upper Valves

With IPO valves, there is a need to take an injection pressure drop from valve to valve to close upper valves. The primary opening and closing force on IPO valves is provided by the injection pressure; an injection pressure drop should be taken between each successive depth to assure that the upper valves are closed when injecting through a lower valve. This required reduction in injection pressure for each lower valve means that the gas-lift mandrels must be spaced slightly closer together than for types of valves that do not require a casing pressure drop between valves.

5.7.2.8 Upper Mandrel Spacing Too Far Apart for PPO Valves

If upper mandrels are too far apart, IPO valves may be needed. Even though the IPO design requires an injection pressure drop between valves, it is possible to work with a wider mandrel spacing than if other types of valves are used. The reason is that the tubing pressure design line for IPO valves may be further to the left (lower tubing pressure) than the tubing pressure design line needed for other types of valves. If it is reasonably certain that neither side of the dual well will need to “work” (inject) in the upper part of the well, the use of IPO valves should present no problem.

5.7.2.9 Switching from IPO Valves to PPO Valves

The operator can use IPO valves in top mandrels (that are further apart) and then can switch to PPO valves deeper in the well. IPO valves can be used for unloading in the upper part of the well, where it is unlikely that the well will need to operate. Lower in the well, where the well may need to operate (inject gas), PPO valves can be used.

5.7.2.10 Nitrogen-charged IPO Valves

IPO valves that are charged with nitrogen (N_2) gas are temperature sensitive. While IPO valves can use springs to provide the closing force, most use N_2 gas in the bellows to provide the closing force. The pressure of the nitrogen is temperature sensitive, so it is necessary to accurately measure or estimate the temperature at the depth of the valves' installation.

5.7.2.11 Using a Choke in IPO Unloading Valves

A choke installed in the valve nose, downstream of the port, can be used in IPO unloading valves. The majority of the pressure drop across the valve occurs at the choke. This keeps the pressure drop across the port lower and holds the valve open until its closing pressure is reached. This prevents throttling, whereby the gas inject rate through the valve decreases as the valve begins to close at a lower tubing pressure.

5.7.3 Balanced IPO (Continuous or Constant Flow) Valve Support, Logic, and Issues

5.7.3.1 General

Another option is to use a balanced IPO, also known as a continuous flow or a constant flow valve. The primary opening force is supplied by the casing (injection) pressure, but unlike normal IPO valves, they have a much greater tubing effect. Normally the R-value, the ratio of the area of the port to the area of the bellows, is approximately 0.25, as compared to 0.10 or less for most common IPO valves. Also, these valves normally have a choke installed upstream of the port of the valve. The choke causes the casing (injection) pressure to drop as gas enters the valve. This makes the closing sensitive to the tubing (production) pressure.

5.7.3.2 Temperature Sensitivity

Balanced IPO valves are sensitive to temperature. Normally, these valves use a nitrogen gas charged bellows as the closing force. The pressure in the bellows is sensitive to temperature, so the temperature at the depth of each valve must be known or estimated for accurate design. It is possible to use a spring as the primary closing force to remove the temperature sensitivity; however, these valves are much less commonly used.

5.7.3.3 Valve Closing Pressure

Balanced IPO valves can be designed on constant P_c but close with a decline in P_t . Since these valves have a significant tubing effect on valve opening and closing, they can be designed based on a constant casing (injection) pressure. A reduction in casing pressure is not required to close the upper valves. They can be designed to close on a reduction in tubing (production) pressure as the well unloads.

5.7.3.4 Unloading Valves

Unloading valves can be locked closed by a decline in P_c after reaching the operating point. As with any IPO valves, these valves can be locked closed by reducing the casing (injection) pressure after the operating depth is reached. This reduction in casing pressure can be achieved if the well is operating from an orifice or a “flag” valve that is designed to operate at a lower casing pressure.

This valve is intended for unloading/kickoff only, not for operating, and the well should operate beneath it on an orifice or IPO valve. Normally, the operating point should be on an orifice or a gas-lift valve designed to operate at a lower casing pressure. However, a balanced IPO valve could also be used if it can be operated at a lower casing pressure than that used for the unloading valves.

5.7.3.5 Design Information

The designer should know P_c , P_t , and T to design; if any of these are unknown, it may not work. To design these valves, it is important to know the casing pressure, tubing pressure, and temperature at the depth of each valve. However, this is also required for other nitrogen charged gas-lift valves.

5.7.4 Selection Criteria for Unloading Valves

The following considerations are recommended for selecting an unloading valve. If the expected depth of lift is known, IPO gas-lift valves should be used for unloading; if the depth of lift is not known, it may be necessary to lift from unloading valves. PPO gas-lift valves should be used for unloading; special gas-lift valves (e.g. balanced IPO valves) should only be used where IPO or PPO valves are not practical.

5.8 Unloading Gas-lift Valves

5.8.1 General

Annex C contains an unloading valve design for PPO gas-lift valves. Gas-lift mandrel example spacing design is included in Annex B.

5.8.2 Unloading Valve Design for Each Type of Valve

A typical design for PPO gas-lift valves is included in Annex C. There are many design programs available where information is available for other valve designs. Options for unloading valves include: PPO gas-lift valves, IPO gas-lift valves, and balanced IPO gas-lift valves.

5.9 Operating Unloading Gas-lift Valves

5.9.1 Unloading Valve(s)

Often the actual depth of gas-lift injection is not known and cannot be predicted with accuracy. This is true for new completions or where the reservoir pressure, inflow productivity, or fluid properties are subject to change. In this case, it may be necessary to operate from an unloading valve either for the long term, or at least until the actual depth of lift can be determined. If the unloading valve is selected and designed to minimize throttling, this can provide acceptable operation. If the well conditions change, the depth of lift can automatically change to another valve.

It may be necessary to operate from more than one unloading valve. In some instances, where the casing (injection) pressure is relatively low, it may not be possible to inject the desired rate at the deepest mandrel depth. In such cases, multipointing or the simultaneous injection into more than one valve may be warranted and may be beneficial. Injection of some gas through an upper valve may lighten the tubing pressure gradient enough to allow more gas to be injected into the next deeper valve, if an appropriate type of valve is used.

Even if gas injection through an upper unloading valve is anticipated, it may be wise to install an orifice, a nozzle venturi orifice, or a “flag” valve in the deepest mandrel in both sides of the dual. In this way, if the well

does work down to the deepest mandrel, this can be seen. If injection through an upper unloading valve is anticipated, the use of PPO or balanced IPO valves is recommended. The reason is that the depth of lift can then be determined by the well's producing conditions. If IPO valves were used, the operating valve would depend on a change in the casing pressure, not the producing conditions of the well.

5.9.2 Alternatives for Operating Gas-lift Valve or Orifice

An unloading gas-lift valve, an orifice, a nozzle venturi orifice, or a "flag" valve may be used for gas-lift injection at the design operating depth. These alternatives are used for the operating points in dual gas-lift designs. If the desired operating depth is known, the recommendation is to use a standard orifice, a nozzle venturi orifice, or a "flag" valve. If the depth of operation is not known, or cannot be predicted with certainty, operation may be from an unloading valve.

5.9.3 Orifice Valves

If the depth of lift is known to be from the deepest gas-lift mandrel, or from some other known depth, many operators install an orifice at this depth. The advantage of the orifice is that it is always fully open. It can accommodate a wide range of gas injection rates without throttling, when flow is not in the critical range. Critical flow occurs when the pressure downstream of the orifice, the tubing pressure, is less than approximately 60 % of the upstream (casing) pressure.

Thus, the injection rate can be adjusted to optimize the performance of the well. This can be done over a wide range of injection rates where the injection pressure is not increased high enough to reopen an upper valve. One of the most common problems with the use of an orifice valve is defining the size of the orifice port. If it is too large, the well will become unstable. The orifice port size should be carefully chosen to allow the correct gas injection rate, and support the desired flexibility, without being large enough to allow well instability. An orifice valve does have a built-in check valve to prevent back flow from the tubing to the casing annulus in cases where the tubing pressure is higher than the casing pressure.

5.9.4 Nozzle Venturi Orifice Valves

If the desired injection rates into one or both sides of the dual gas-lift well are known, a nozzle venturi-orifice may be used. A nozzle venturi is an orifice with a venturi configuration on the valve port. The venturi design causes the critical flow to occur when the pressure downstream of the port is less than approximately 92 % of the upstream pressure. This means that as long as the critical flow range can be maintained, the gas injection rate can be held at a constant value. This can be very advantageous in a dual gas-lift well. The desired injection rate into each side of the dual can be designed and maintained, with the upstream (casing) pressure maintained and while the downstream (tubing) pressure is kept below 92 % of the upstream (casing) pressure. Unlike the simple orifice, the nozzle venturi does not provide flexibility in gas injection rate, so it does not support hands-on changing of the injection rate to optimize the well. The desired injection rate should be determined in advance, and the nozzle venturi should be sized for this rate.

5.9.5 Flag Valve (PPO, IPO, Balanced IPO Designs)

Rather than using an orifice or a nozzle venturi, some operators prefer to use a "flag" valve in the bottom gas-lift mandrel. A "flag" valve is a normal PPO, IPO, or balanced IPO valve that is designed to operate at a lower injection pressure than the unloading valves. It is normally held fully open by the injection and production pressures at depth, but if the pressures fall too low for some reason, this valve, unlike an orifice or nozzle venturi, can close.

5.10 Designing for Dual Gas-lift if Mandrels Spaced Too Far Apart

5.10.1 General

In some cases, the upper gas-lift mandrels may be spaced too far apart to support use of PPO or other types of gas-lift valves. In this case, it may be necessary to use IPO valves or other approaches to unload the well.

5.10.2 IPO Valves in Upper Mandrels

IPO valves may be necessary in upper mandrels. IPO valves can work with a wider mandrel spacing than can PPO or balanced IPO valves. If there is little possibility that the well will need to operate from these upper mandrels, the use of IPO valves is a logical choice.

5.10.3 Use of Pack-off Valves

If for some reason use of IPO valves does not appear feasible, use of a pack-off valve can be considered. This might be necessary if the upper mandrel spacing was too wide, even for IPO valves. A pack-off valve requires that a hole be punched in the tubing and the pack-off valve is set across the hole. A disadvantage of this is that it is not possible to perform wireline work beneath the pack-off device, unless it is removed.

5.10.4 Use of Concentric String

A third option, if the production tubing is large enough, could be to install an insert concentric tubing inside the primary production tubing. This concentric tubing could be outfitted with the necessary gas-lift mandrels/valves to permit unloading.

5.11 Dual Gas-lift System Design Options

5.11.1 General

Several options are discussed for selecting types of gas-lift valves for dual gas-lift. It is not the purpose of this RP to give specific recommendations on these options. However, they are listed in this section for consideration by those who operate dual gas-lift wells.

5.11.2 PPO Valves on Both Sides

Some operators choose to use PPO valves on both sides (in both tubing strings) of a dual gas-lift well. They normally install an orifice or venturi orifice valve in the bottom (or lowest) operating valve. Their reasoning for this is typically twofold:

- 1) use of PPO valves can allow the well to work down with less loss in casing pressure; and
- 2) if one zone (side of the dual) needs more or less gas than the other side, this can be better accommodated by PPO valves than by IPO valves, where the valve opening/closing is more controlled by the injection (casing) pressure.

5.11.3 IPO Valves High in the Hole, PPO Valves Lower in the Hole

Some operators suggest it may be preferable to use IPO valves higher in the well and PPO valves lower. The logic of this is that it may be easier to unload a well using IPO valves, but PPO valves should be used in the lower portion of the well, where most wells are operated. This logic is supported by the fact that a dual well needs to be unloaded once to remove the liquid from the casing/tubing annulus; this is accomplished with an IPO design. When the well is unloaded, the operation can be fine-tuned by using PPO valves near the operating depth.

5.11.4 IPO Valves on One Side, PPO Valves on the Other Side

An alternative to the approach in 5.11.3 is to use IPO valves on one side of the dual and PPO valves on the other side. The logic of this approach is similar; the side with the IPO valves can be used to unload the well, with the other side closed in during the unloading process. Then, the well can be placed on gas-lift with both sides open. The advantage of this is that unloading to bottom can be achieved with relative assurance. The potential disadvantages of this approach are:

- a) the casing pressure will be somewhat reduced by unloading with IPO valves, and

- b) the side with the IPO valves may tend to “rob” gas from the other side.

If this approach is used, relatively small-ported gas-lift valves, and a small orifice, should be used to prevent either side from taking too much gas. Also, use of chokes in the gas-lift valves should be considered.

5.11.5 IPO Valves on Both Sides

A further alternative is to use IPO valves on both sides. This alternative can work if both zones are well understood, the depth of lift for both zones can be accurately predicted, and the amount of gas required by both zones can be accurately predicted so the port sizes or choke sizes can be accurately designed for both sides of the dual. Unfortunately, it is usually not possible to accurately know these factors. When one or both wells change, the injection rate may require change and it may be difficult to accommodate with IPO valves on both sides.

5.11.6 Single-point Injection

Where there is sufficient gas injection pressure available to inject from bottom without the need to install unloading valves, single-point injection can be used by injecting through an orifice just above the depth of the dual packer. This can work very well where the sizes of the orifices are chosen to prevent over-injection.

6 Dual Gas-lift Well Operations

6.1 General

In most production organizations, regardless of who designed the artificial lift systems, it is left to the production operations staff to operate the well and to try to do so successfully over the long term. Operating any gas-lift well can be a challenge, and operating a dual gas-lift well can be more challenging. This section defines the issues to be addressed to successfully operate dual gas-lift wells over the long term.

6.2 Installing Dual Gas-lift Equipment

6.2.1 Running Two Strings Together Simultaneously

When installing dual gas-lift equipment in a well, it is usually recommended to run both tubing strings at the same time (simultaneously). To do this, the following conditions should be met.

- a) There must be a dual set of slips.
- b) There must be a dual string elevator.
- c) There must be sufficient clearance in the casing annulus so both strings and their gas-lift mandrels can be run into the well simultaneously.
- d) The two sets of mandrels must be able to pass one another if one side must be pulled while the other is left in place, or if the mandrels on the short string must pass those on the long string when the short string is stung into the dual packer.
- e) One string, normally the long string, should be stacked in the derrick first. Then, the second (short) string picked up from the rig floor.
- f) The dual packer must be run on the long string.
- g) The short string must be stung into the dual packer once it is at the desired depth.

6.2.2 Running Two Strings Separately

If the two strings are run separately, the installation can be more complicated. The following should be considered when running two strings separately:

- a) the long string should be run first,
- b) there must be sufficient clearance in the casing annulus so the short string and its mandrels can pass down the annulus and past the long string and its mandrels that are already in place,
- c) the dual packer must be run on the long string,
- d) the short string must be stung into the dual packer once it is at the desired depth.

6.2.3 Multiple Packers on Long String

There will always be at least two packers on the long string: the long-string packer that is set above the deeper zone, and the dual packer that is set above the shallower zone. In some cases, there may be a need for more packers if, for example, an intermediate zone is to be isolated and saved for potential future completion using a sliding sleeve. Proper setting and testing of each packer is essential. It is recommended to plan the installation with an expert from the packer supplier and have this person on location to assist with setting and testing the packers during the installation procedure.

6.2.4 Surface-controlled (Electric, Hydraulic, Cableless) Gas-lift Valves

Some operators consider the use of surface-controlled gas-lift valves. These may be operated by electric power with electric cables, hydraulic power with hydraulic lines, or by using cableless electric power transmission. It is recommended that an operator become familiar with using these types of systems on single completions before attempting to use them on dual gas-lift wells. Some considerations when using this technology on a dual gas-lift well are as follows.

- a) Whenever use of this technology is considered, plan the installation with an expert from the surface control service provider. Have this person on location to assist in running and testing the equipment.
- b) When using electric cables or hydraulic lines, the lines should be strapped to each tubing string, with at least five straps per tubing joint, to avoid any cable or line slack or movement.
- c) The tubing strings should be run at the same time to avoid damaging the cables or lines when passing a gas-lift mandrel on the other string.
- d) Electric or hydraulic continuity should be tested as every few joints of tubing strings are run. If a problem is found, the tubing strings should be pulled and the problem corrected.
- e) When using cableless electric power transmission, the two tubing strings should be electrically isolated and from the casing.

6.2.5 Chemical Injection Lines

In some cases, lines are run so chemicals can be injected deep in the well for corrosion control, prevention of scale formation, control of paraffin, etc. It may be sufficient to run one chemical line for the dual well; in other cases, a separate line is needed for each string. When planning the installation, the same considerations are important as defined for installing electrical lines or hydraulic cables. In addition, chemical lines may be connected to mandrels that are designed to inject chemical into the tubing.

6.2.6 Testing the Packer

The packer test is an important part of the procedure in dual gas-lift completions. A dual completion with a leaking packer will have communication between the two producing zones through the gas-lift valves.

packer test procedure depends on whether the completion has been set up with dummy valves or live gas-lift valves. Test the casing to 10,342 kPa (1500 psi) or another recommended pressure to check for leaks in the casing, tubing strings, and dual packer. If the pressure cannot be held stable for 30 minutes without bleed-off, the casing leak should be repaired. The following describes test procedures depending on the valve type.

- a) **Dummy Valves**—The casing can be pressured up to the desired pressure and held for 30 minutes.
- b) **Live Gas-lift Valves**—A plugging device should be set at the bottom of the production strings, below all live gas-lift valves, and then they are pressured up to a predetermined limit. This will energize and seal the checks in the live gas-lift valves. Holding this pressure on both tubing strings will allow pressure to be placed on the casing for a packer test with no interference from the live gas-lift valves. The plugging device is typically a standing valve set with slick line or a ceramic flapper that can be broken with either pressure or slick line after the test.

Some wells that are completed with gas-lift equipment will flow naturally for a long period of time. During the natural flowing period, leaks can develop in the tubing strings, casing string, or the packer. If any type of leak is suspected, the procedure above can be reapplied before gas-lifting the well to ensure good system integrity.

6.3 Dual Gas-lift Well Wireline Operations

6.3.1 General

Successful wireline operations are essential for successful dual gas-lift. Recommendations for successful operations while changing gas-lift valves are presented below.

6.3.2 Possibility of Cross-flow When Changing Gas-lift Equipment

When changing out gas-lift valves in a dual completion, it should be recognized that the string being worked on may have a higher bottomhole pressure (BHP) than that of the opposite string. When a gas-lift valve is pulled from the higher pressured string, the tubing pressure will equalize with the casing pressure through the empty gas-lift mandrel. Cross-flow of well fluids may occur from the string being worked on, through the empty gas-lift mandrel, into the annulus, through the opposite string's gas-lift valve(s), and into that opposite string's wellbore. Although check valves are incorporated in the gas-lift valves to prevent wellbore fluids from flowing into the annulus, this is a moot point when the gas-lift valve is pulled out. Cross-flow, which can be at very high flow rates, can easily cut out the seats in the gas-lift valve(s) in the opposite string. This can cause problems and add to troubleshooting confusion with the dual completion after a gas-lift valve replacement.

Cross-flow can even prevent the proper setting of gas-lift valves within the mandrel pocket. As the bottom seal assembly is driven past the upper polish bore area in the mandrel pocket, cross-flow will be from the bottom of the mandrel, out through the mandrel ports, and into the annulus. As the valve is jarred further into the pocket, it has to overcome the upward force of the cross-flow through the mandrel. The wireline operator may think that the valve is set, allowing the latch to lock into the latch profile. The wireline operator then jars up to shear off and inadvertently pulls the valve out of the pocket or leaves the valve partially within the pocket. The following should be considered when changing gas-lift valves in a dual well.

6.3.3 Changing Gas-lift Valves in a Dual Completion

6.3.3.1 Opposite String Has Lower Pressure than Working String

Set a wireline plug or a standing valve with an equalizing assembly in the opposite string to prevent cross-flow. Set a valve catcher (wireline landing nipple lock, plug, standing valve, etc.) in the working string to catch dropped tools, or set a wireline plug with an equalizing assembly in the working string to prevent cross-flow from the working string and also act as a valve catcher.

6.3.3.2 Opposite String Has a Higher Pressure than the Working String

There is no need to set a plug in the opposite string, as the check valve in the gas-lift valves will prevent cross-flow. As a precaution, the tubing in the opposite string should be pressure tested to ensure that the